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**DEPARTMENT OF THE NAVY**  
**NAVAL FACILITIES ENGINEERING COMMAND**  
**LITIGATION OFFICE**  
**720 KENNON STREET SE ROOM 136**  
**WASHINGTON NAVY YARD DC 20374-5051**

IN REPLY REFER TO

April 30, 2010

Jocelyn Boyd, Chief Clerk  
Public Service Commission of SC  
Post Office Drawer 11649  
Columbia, SC 29211

Re: Application of South Carolina Electric & Gas Company  
For Adjustments and Increases in its Electric Rate Schedules and Tariffs  
DOCKET NO. 2009-489-E

Dear Ms. Boyd:

Enclosed please find the original and 25 copies of the Prefiled Direct Testimony and Exhibits of Nicholas Phillips, Jr. filed on behalf of the Navy and all Federal Executive Agencies.

Sincerely,

AUDREY VAN DYKE  
For the Secretary of the Navy  
And all Federal Executive Agencies  
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**Before the Public Service Commission of South Carolina**

**Docket No. 2009-489-E**

**In Re: Application of South Carolina  
Electric & Gas Company for  
Adjustments and Increases in the  
Company's Electric Rate  
Schedules and Tariffs**

**NOTICE OF CHANGE AND  
APPLICATION FOR  
INCREASE  
IN RATES AND CHARGES**

Direct Testimony and Exhibits of

**Nicholas Phillips, Jr.**

On behalf of

**Federal Executive Agencies**

April 28, 2010  
Project 9280



**BRUBAKER & ASSOCIATES, INC.  
ST. LOUIS, MO 63141-2000**

**Before the Public Service Commission of South Carolina**

**Docket No. 2009-489-E**

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Electric & Gas Company for  
Adjustments and Increases in the  
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**NOTICE OF CHANGE AND  
APPLICATION FOR  
INCREASE  
IN RATES AND CHARGES**

**Direct Testimony of Nicholas Phillips, Jr.**

1    **Q     PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

2    A     Nicholas Phillips, Jr. My business address is 16690 Swingley Ridge Road, Suite 140,  
3     Chesterfield, MO 63017.

4    **Q     WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?**

5    A     I am a consultant in the field of public utility regulation and managing principal with the  
6     firm of Brubaker & Associates, Inc., energy, economic and regulatory consultants. I have  
7     testified in many electric and gas rate proceedings on virtually all aspects of ratemaking.  
8     More details are provided in Appendix A of this testimony.

9    **Q     ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?**

10   A     I am appearing on behalf of the Federal Executive Agencies. Our firm is under contract  
11     with The United States Department of the Navy to perform cost of service, rate design  
12     and related studies. The Department of the Navy represents the Department of Defense  
13     and all other Federal Executive Agencies (FEA) in this proceeding.

1    **Q     HAVE YOU PRESENTED TESTIMONY IN PRIOR PROCEEDINGS BEFORE THE**  
2           **SOUTH CAROLINA PUBLIC SERVICE COMMISSION (COMMISSION OR SCPSC)?**

3    **A     Yes. I have been involved in many prior proceedings before this Commission**  
4           **concerning South Carolina Electric and Gas (SCE&G), as well as other utilities.**

5    **Q     WHAT IS THE SUBJECT MATTER OF YOUR TESTIMONY?**

6    **A     I am presenting testimony concerning the appropriate cost allocation methodology for**  
7           **use in this proceeding, the revenue distribution to classes of any amount of rate increase**  
8           **granted by the Commission, and the proper design of SCE&G's electric rates. There are**  
9           **certain general principles that should form the basis for cost allocation, revenue**  
10          **distribution, and rate design. I have examined the testimony and exhibits presented by**  
11          **SCE&G in this proceeding with respect to cost allocation and rate design, I will comment**  
12          **upon the propriety of these proposals and make certain recommendations.**

13   **Q     DOES YOUR TESTIMONY ADDRESS SCE&G'S NEED FOR AN INCREASE IN**  
14          **ELECTRIC RATES?**

15   **A     No. In order to make my presentation consistent with the revenue levels requested by**  
16          **SCE&G, I have, in many instances, used their numbers for rate base, operating income,**  
17          **and rate of return. Use of these numbers should not be interpreted as an endorsement**  
18          **of them for purposes of determining the total dollar amount of rate increase to which**  
19          **SCE&G may be entitled. I recommend the appropriate distribution to classes of any**  
20          **amount of rate increase allowed by the Commission.**

**Summary of Conclusions and Recommendations**

**Q PLEASE SUMMARIZE YOUR RECOMMENDATIONS IN THIS PROCEEDING.**

**A** A summary of my position and recommendations is listed below:

1. SCE&G's electric rates should be based on the cost of providing service to each customer class.
2. Having analyzed SCE&G's summer peak, winter peak, and load pattern, I conclude that the summer peak responsibility cost of service study is appropriate for use in this proceeding. It properly allocates cost responsibility to customer classes and, if implemented properly, minimizes the need for new generating capacity consistent with SCE&G's load management goals.
3. SCE&G's proposed distribution of its requested rate increase is based on cost of service and moves all rate classes toward the system average rate of return. However, the data for the large general service class cannot be considered normal in this case, the measured movement toward cost of service is appropriate.
4. I recommend distributing the approved rate increase in a manner that will move all classes closer to cost as proposed by SCE&G. Any increase granted should be distributed to classes in proportion to the increase proposed by SCE&G, which is shown on Schedule 1 of Exhibit NP-2.

**Cost of Service and Rate Design Principles**

**Q PLEASE EXPLAIN THE BASIS FOR YOUR EVALUATION AND DESIGN OF RATES.**

**A** The ratemaking process has three steps. First, the determination of the utility's total revenue requirement and whether an increase in revenues is necessary. Second, we must determine how any increase in revenues is to be distributed among the various customer classes. A determination of how many dollars of revenue should be produced by each class is essential for obtaining the appropriate level of rates. Finally, individual tariffs must be designed to produce the required amount of revenues for each class of service and to reflect the cost of serving customers within the class.

The guiding principle at each step should be cost of service. In the first step – determining revenue requirements – it is universally agreed that the utility is entitled to an increase only to the extent that its actual cost of service has increased. If current rate

1 levels exceed revenue requirement, a rate reduction is required. In short, rate revenues  
2 should equal actual cost of service. The same principle should apply in the second two  
3 steps. Each customer class should, to the extent practicable, produce revenues equal  
4 to the cost of serving that particular class, no more and no less. This may require a rate  
5 increase for some classes and a rate decrease for other classes. The standard tool for  
6 determining this is a class cost of service study that shows the rates of return on each  
7 class of service. Rate levels should be modified so that each class of service provides  
8 approximately the same rate of return. Finally, in designing individual tariffs, the goal  
9 should also be to relate the rate design to the cost of service so that each customer's  
10 rate equals, to the extent practicable, the utility's cost of providing that service.

11 **Q WHY IS IT IMPORTANT TO ADHERE TO BASIC COST OF SERVICE PRINCIPLES IN**  
12 **THE RATE DESIGN PROCESS?**

13 **A** The basic reasons for using cost of service as the primary factor in the rate design  
14 process are equity, engineering efficiency (cost minimization), conservation, and  
15 stability.

16 **Q HOW IS THE EQUITY PRINCIPLE ACHIEVED BY BASING RATES ON COSTS?**

17 **A** When rates are based on cost, each customer (to the extent practical) pays what it costs  
18 the utility to provide service to that customer, no more and no less. If rates are not  
19 based on cost of service, then some customers contribute disproportionately to the  
20 utility's revenues by subsidizing service provided to other customers. This is inherently  
21 inequitable.

1   **Q     HOW DO COST-BASED RATES ACHIEVE THE ENGINEERING EFFICIENCY (COST**  
2       **MINIMIZATION) OBJECTIVE?**

3   **A**Cost minimization is achieved when customers receive the appropriate price signals  
4       through the rates that they pay. Rate design is the step that follows the allocation of  
5       costs to classes, it is important that the proper amounts and types of costs be allocated  
6       to the customer classes so that they may ultimately be reflected in the rates.

7           When the rates are designed so that the energy costs, demand costs, and  
8       customer costs are properly reflected in the energy, demand, and customer components  
9       of the rate schedules, respectively, customers are provided with the proper incentives to  
10      minimize their costs, which will in turn minimize the costs to the utility.

11          From a rate design perspective, over-pricing the energy portion of the rate and  
12      under-pricing the fixed components of the rate (such as customer and demand charges)  
13      will result in a disproportionate share of revenues being collected from high load factor  
14      customers.

15   **Q     PLEASE GIVE AN EXAMPLE.**

16   **A**I will focus upon the two components of the rates applicable to large customers that are  
17      predominant in terms of cost causation and revenue collection. These are the demand  
18      component and the energy component.

19          Assume that a given dollar amount of revenue is to be collected from application  
20      of these two elements. From a rate design perspective, various combinations of  
21      revenue collections from the demand and energy charge are, of course, possible.  
22      These possibilities range from the collection of all such costs through an energy charge,  
23      with no collection through the demand charge, to the collection of all such costs through  
24      a demand charge, with no collection through the energy charge. Obviously, neither of

1 these extreme possibilities reflect reasonable rate design since there are definite  
2 demand and energy components to the cost of serving customers.

3 In between these two extremes, there is a range of possibilities. The most  
4 obvious possibility is to base the demand charges on the demand costs and the energy  
5 charges on the energy costs. To the extent that there is an overall correspondence  
6 between costs and revenues to be collected, basing the demand charge on the demand  
7 cost and the energy charge on the energy cost will most closely charge each customer  
8 with the appropriate revenue responsibility.

9 To illustrate the cost minimization concept, assume that a cost-based rate would  
10 contain a \$15 per kilowatt (kW) demand charge and a 2¢ per kilowatthour (kWh) energy  
11 charge. Suppose, however, that an alternate rate was instead designed with a \$3.00  
12 per kW demand charge and a 5¢ per kWh energy charge. (It is implicit that application  
13 of both of these rates to the total class test year billing determinants would produce the  
14 same total revenue.)

15 Consider the effect of the alternate rate as compared to the cost-based rate.  
16 When a customer faces a demand charge of \$3 per kW, the price signal he gets is that  
17 imposition of peak demands on the utility's system is not very costly. Thus, there is less  
18 incentive to control peak loads with a below-cost demand charge than if the customer  
19 faces a demand charge that more nearly approximates demand costs. To the extent  
20 that the customer reacts to this below-cost demand charge, the tendency will be for  
21 system peak loads to be higher than otherwise, which will impose additional costs on the  
22 utility – costs that may have to be collected from all customers.

23 Consider now the effect of charging an energy rate of 5¢ per kWh, as compared  
24 to an energy cost of 2¢ per kWh. The customer is influenced to use less energy than  
25 would be the case if the rates were cost-based. This will tend to increase customer  
26 preferences for alternate energy supplies, and particularly so for high load factor

1 customers who use a large amount of energy in relation to their peak load. This problem  
2 becomes particularly exacerbated if significant overcharges occur during the low load  
3 (off-peak) periods on the utility's system, when additional energy consumption at lower  
4 rates would be beneficial to the system.

5 **Q HOW DO COST-BASED RATES FURTHER THE GOAL OF CONSERVATION?**

6 **A** Conservation occurs when wasteful or inefficient uses are discouraged or minimized.  
7 Only when rates are based on actual costs do customers receive a balanced price signal  
8 against which to make their consumption decisions. If rates are not based on costs,  
9 then customers may be induced to use electricity inefficiently in response to the distorted  
10 signals. It is important that the costs associated with certain conservation and demand  
11 management programs should not create a new form of subsidization and move rates  
12 away from cost.

13 **Q PLEASE DISCUSS THE STABILITY CONSIDERATION.**

14 **A** When rates are closely tied to costs, the earnings impact on the utility of changes in  
15 customer use patterns will be minimized as a result of rates being designed in the first  
16 instance to track changes in the level of costs. Thus, cost-based rates provide an  
17 important enhancement to a utility's earnings stability, reducing its need for filings for  
18 rate increases.

19 From the perspective of the customer, cost-based rates provide a more reliable  
20 means of determining future levels of power costs. If rates are based on factors other  
21 than costs, it becomes much more difficult for customers to translate expected  
22 utility-wide cost changes (i.e., expected increases in overall revenue requirements) into  
23 changes in the rates charged to particular customer classes (and to customers within the

1 class). This situation reduces the attractiveness of expansion, as well as of continued  
2 operations, because of the lessened ability to plan.

3 **Q WHEN YOU SAY "COST," TO WHAT TYPE OF COST ARE YOU REFERRING?**

4 A I am referring to the utility's "embedded" or actual accounting costs of rendering  
5 services; that is, those costs that are used by the Commission in establishing SCE&G's  
6 overall revenue requirement.

7 **SCE&G Cost of Service Study**

8 **Q IS SCE&G'S PROPOSED COST OF SERVICE METHODOLOGY APPROPRIATE FOR**  
9 **USE IN THIS PROCEEDING?**

10 A Yes. However, it should be noted that SCE&G did not provide an electronic model of its  
11 filed cost of service study required to verify the numerous calculations incorporated  
12 within the cost of service study.

13 The cost study functionalizes and classifies costs in accordance with generally  
14 accepted cost of service principles. Demand related costs are allocated on demands  
15 placed on the system. Energy related costs are allocated on the quantity of energy  
16 consumed and customer related costs are allocated on the number of customers.

17 **Q IN CONNECTION WITH YOUR ANALYSIS, DID YOU HAVE AVAILABLE TO YOU**  
18 **ANY COST OF SERVICE STUDIES?**

19 A Yes, I did. I had information made available to me, which included summer coincident  
20 peak cost of service studies for the 12-month period ended September 30, 2009 that  
21 were produced and furnished by SCE&G. The most appropriate cost of service for use  
22 in this proceeding is the summer coincident peak responsibility method proposed by

1 SCE&G consistent with past practice. This method has been consistently utilized by  
2 SCE&G and approved by this Commission since 1980 or approximately 30 years. Use  
3 of the summer coincident peak study will provide the most accurate evaluation of the  
4 cost to serve various customer classes. The use of the summer coincident peak method  
5 is also the most consistent with actual load analysis and operation of the SCE&G electric  
6 system. Cost allocation methods that directly utilize annual energy usage to allocate  
7 production investment, such as the peak and average or similar method, are completely  
8 inappropriate for use in this proceeding and should not be utilized for cost of service or  
9 serve as the basis of rate design.

#### 10 **Cost of Service Analysis**

11 **Q MR. PHILLIPS, PLEASE DESCRIBE SCHEDULE 1 OF EXHIBIT NP-1.**

12 **A** Schedule 1 shows the load factors for the SCE&G rate classes, based on their summer  
13 coincident peak demand for this test period. The load factor for the large general  
14 service class of 85.0% is substantially higher than the load factors for the other major  
15 classes of customers. The residential class load factor is 49.2% and the small general  
16 service class load factor is 53.7% for the test year ended September 30, 2009.

17 **Q HOW DID YOU COMPUTE THE LOAD FACTORS SHOWN IN SCHEDULE 1?**

18 **A** I divided the kWh generated for a customer class by the product of the coincident peak  
19 demand asserted on the system by that class and the number of hours in the test year  
20 (8,760). The following equation shows the relationship between annual load factor,  
21 energy and demand.

$$22 \text{ Load Factor} = \text{Energy/Demand} \times 8760$$

1    **Q     PLEASE EXPLAIN THE SIGNIFICANCE OF THE LOAD FACTOR.**

2    **A     Load factor is an indication of the degree of utilization of the demand imposed upon the**  
3       utility system by a customer (or class of customers). It relates average use of the  
4       system to the maximum use at any one time. Load factor is an important indicator of the  
5       cost of serving a customer class, since fixed costs, including capital expenditures,  
6       return, depreciation, and certain taxes and expenses, are determined by the magnitude  
7       of demands imposed upon the system, and do not vary with the number of kWh  
8       produced or consumed. Stated in another manner, the fixed costs would still exist if  
9       sales were to decline. As load factor increases, the fixed costs related to the maximum  
10      demands imposed upon the system are spread over a larger number of kWh, resulting in  
11      lower per unit power costs. Similarly, as load factor decreases, higher per unit costs  
12      result.

13   **Q     DOES THE VOLTAGE LEVEL OF SERVICE AFFECT COST OF SERVICE?**

14   **A     Yes. Sales by voltage level of service for each rate class are shown on Exhibit NP-1,**  
15      Schedule 2. Service at higher voltage levels generally results in lower cost of providing  
16      service. The residential and street lighting classes purchase all of their power at the  
17      distribution voltage level. Since no power is supplied to the residential and street lighting  
18      classes directly from the high voltage levels, it is necessary for the Company to make  
19      investments in both primary and secondary distribution lines, as well as transmission  
20      lines and facilities, to provide service to these customer classes.

21           For large general service customers, approximately 60% of sales occur at the  
22      transmission voltage level or sub-transmission voltage level. Therefore, in supplying  
23      energy to a large portion of these large general customers, it is unnecessary for the  
24      SCE&G to make any investments or related expenditures in secondary or primary  
25      voltage distribution facilities. Since SCE&G is generally not required to incur costs

1 below the transmission and sub-transmission voltage levels to serve many of these large  
2 general service customers, the cost per kWh of serving them is lower than the cost of  
3 serving those customers who require the lower voltage distribution system. In addition,  
4 energy losses are inversely related to voltage level of service resulting in less fuel per  
5 kWh required to serve higher voltage level large general service customers.

6 **Q MR. PHILLIPS, HAVE YOU ANALYZED DATA TO CONSIDER THE ECONOMIES OF**  
7 **SCALE ASSOCIATED WITH SCE&G'S CUSTOMER-RELATED COSTS?**

8 **A** Yes. Exhibit NP-1, Schedule 3 shows the average kWh sales per customer for SCE&G's  
9 major classes of service for the 12 months ended September 30, 2009. As can be seen  
10 in Schedule 3, large general service customers as a class purchased substantially more  
11 power per customer service than any of the other classes. For example, the average  
12 large general service customer used more than 1,500 times as many kWh as did the  
13 average residential customer.

14 These large differences in average kWh sales per customer for the various  
15 customer classes result in economies of scale in customer-related costs, such as meter  
16 reading, billing, and customer accounting expense, producing much lower  
17 customer-related costs per kWh sold to these large general service customers.

18 **Q HAVE YOU CONSIDERED THE RELATIONSHIP BETWEEN INVESTMENT IN PLANT**  
19 **AND KWH SALES FOR SCE&G'S CUSTOMER CLASSES?**

20 **A** Yes. Exhibit NP-1, Schedule 4 shows SCE&G's proposed rate base as SCE&G  
21 allocated it to the customer classes in its coincident peak cost of service study,  
22 expressed on a per kWh basis. As shown in Schedule 4, much less investment is  
23 required on a per kWh basis to serve the large general service customers than to serve  
24 any other class of customers.

1    **Q    HAVE YOU ALSO CONSIDERED THE RELATIONSHIP BETWEEN OPERATING**  
2    **EXPENSES AND KWH SALES FOR SCE&G'S CUSTOMER CLASSES?**

3    **A** Yes. Exhibit NP-1, Schedule 5 shows operating expenses as SCE&G allocated them to  
4    the customer classes in its coincident peak cost of service study, expressed on a per  
5    kWh basis. Schedule 5 shows that significantly lower operating expenses are incurred  
6    per kWh sold to large general service customers than are incurred per kWh sold to  
7    residential or commercial customers.

8    **Q    PLEASE SUMMARIZE THE DATA SHOWN IN SCHEDULES 1 THROUGH 5 OF**  
9    **EXHIBIT NP-1.**

10   **A** These schedules demonstrate how, on a per kWh basis, the costs of serving the large  
11   general service customers are much lower than the costs of serving smaller customers.  
12   Cost-based utility rates should reflect these differences.

13   **Q    MR. PHILLIPS, ARE RATES THAT REFLECT THE LOWER COSTS PER KWH OF**  
14   **ENERGY SOLD TO LARGE GENERAL SERVICE CUSTOMERS CONSISTENT WITH**  
15   **THE CONCEPT OF EQUITABLE RATES TO ALL ELECTRIC CUSTOMERS?**

16   **A** Yes, absolutely. As demonstrated in Schedules 1 through 5 of Exhibit NP-1, SCE&G's  
17   costs to produce and deliver a kWh to a large general service customer are substantially  
18   less than its costs to produce and deliver a kWh to smaller users, such as a residential  
19   or a small general service customer. Equitable rates between customer classes are not  
20   determined by looking at the price paid per kWh. They are determined by evaluating  
21   whether the rates paid reasonably reflect the costs incurred by the utility. This  
22   determination is made by analyzing, in a cost of service study, whether each customer  
23   class is providing the utility with a rate of return substantially equal to the system

1 average rate of return. If each class is providing essentially equal rates of return, then  
2 the rates are equitable among customer classes.

3 **Analysis of Electric Load Characteristics**

4 **Q HAVE YOU REVIEWED CERTAIN PERTINENT LOAD CHARACTERISTICS OF**  
5 **SCE&G'S ELECTRIC SYSTEM?**

6 **A** Yes. I have reviewed SCE&G's load characteristics for the test year and I am generally  
7 familiar with the load characteristics of the SCE&G electric system.

8 SCE&G typically has a dominant summer coincident peak that occurs in the  
9 afternoon on a weekday in July or August. SCE&G's retail system load factor was  
10 60.95% for the test year based on the peak day four-hour band methodology as utilized  
11 by the Company for many years as shown on Schedule 1 of Exhibit NP-1. An electric  
12 system load factor in this range is generally characteristic of a utility with a dominant  
13 annual system peak.

14 **Q HAVE YOU HAD AN OPPORTUNITY TO REVIEW FORECAST PEAK LOAD DATA?**

15 **A** Yes. Schedule 6 of Exhibit NP-1 is an analysis of SCE&G's load forecast and load  
16 pattern as outlined in the 2010 Integrated Resource Plan as filed in Docket No.  
17 2009-9-E. The Company projects dominant and increasing summer peak demands over  
18 the entire 15 year planning horizon. The load factor continues to decline and is  
19 projected to decrease to 52.4% by 2024. This data shows a clear and continued  
20 dominance of the summer peak. It is important to recognize that SCE&G uses its  
21 annual summer planning peak to calculate its system reserve margin, which is a main  
22 indicator of a utility's capacity requirement. As reserve margins decrease, additional  
23 capacity is required to serve the system load in a reliable manner. Capacity is basically

1 the rated capability of a generating station or transmission line. As reserve margins  
2 decrease, additional capacity is required to maintain reliable service. New generating  
3 and transmission capacity requires long lead times and generally increases costs to  
4 ratepayers.

5 **Q HOW DOES THIS FORECAST PEAK LOAD DATA RELATE TO THE APPROPRIATE**  
6 **COST OF SERVICE METHODOLOGY?**

7 **A** A method of cost allocation which allocates some portion of fixed production cost on  
8 annual energy usage, such as the "peak and average" method (or other energy-based  
9 methods), would not adequately account for the dominant summer coincident peak and  
10 therefore fail to reflect the actual load characteristics of the SCE&G system. Allocating  
11 production investment on average demand or kWh signals customers that a demand  
12 created at a peak hour is the same as a demand created during an off-peak hour and is  
13 in conflict with SCE&G's demand management goals. The average of the 12 coincident  
14 peak method is also not appropriate for cost allocation since SCE&G's monthly peaks  
15 are neither equal in importance nor indicative of cost causation. The 12 coincident peak  
16 method and the peak and average method (which also relies on off-peak periods and on  
17 annual energy consumption) are at odds with SCE&G's present and proposed rates that  
18 charge customers substantially more for demands created during the summer months.

19 As previously stated, SCE&G data indicates that its capacity expansion planning  
20 is based on forecasted summer peak loads. As summer peak demands increase,  
21 reserve margins decrease which translates into the need for additional capacity.  
22 SCE&G is basically adding generation capacity to meet its forecasted summer peak  
23 demands. Therefore, I recommend that the Commission adopt the summer coincident  
24 peak method of cost allocation consistent with past practice.

**Allocation of Production Investment**

**Q IN YOUR OPINION, IS IT APPROPRIATE TO CLASSIFY ALL PRODUCTION INVESTMENT AS DEMAND-RELATED?**

**A** Yes. Consumers take for granted that when they flip the switch, an electric light or appliance will turn on and run. Since electric energy cannot be stored in large quantities for any significant length of time, utilities must provide adequate generating capacity to meet the demands of their customers when those customers decide to make those demands. Therefore, investment in generation plant is properly classified as a demand-related cost.

**Q WHAT ABOUT THE ARGUMENT THAT SOME PORTION OF THE INVESTMENT IN BASE LOAD PLANT SHOULD BE CLASSIFIED AS ENERGY-RELATED, BASED ON THE THEORY THAT A UTILITY IS WILLING TO MAKE CERTAIN ADDITIONAL CAPITAL INVESTMENTS TO REDUCE ITS LEVEL OF FUEL COSTS?**

**A** With respect to this argument, it should be noted that the economic choice between a base load plant and a peaking plant must consider both capital costs and operating costs, and therefore is a function of average total costs. The capital cost of peaking plants is lower than the capital cost of base load plants, but the operating costs of peaking plants are higher than the operating costs of base load plants. Moreover, when the hours of use are considered, the fixed cost per kWh for base load plant is usually less than the fixed cost per kWh for the peaking plant. Of course, since the fuel costs of base load plants are lower than the fuel costs of peaking plants, the overall cost per kWh for base load plants is also less than the overall cost per kWh for peaking plants.

It is necessary, therefore, to look at both capital costs and operating costs in light of the expected capacity factor of the plant. The fact that base load plants have lower

1 fuel costs than peaking plants does not mean that the investment in base load plants is  
2 strictly to achieve lower fuel costs. Investment in a base load plant would be made to  
3 achieve lower total costs, of which fixed costs and fuel costs are the primary ingredients.

4 For any given system, the capital costs are not a function of the number of kWh  
5 generated, but are fixed and therefore are properly related to system demands, not to  
6 kWh sold. These costs are fixed in that the necessity of earning a return on the  
7 investment, recovering the capital cost (depreciation), and operating the property are  
8 related to the existence of the property and not to the number of kWh sold. If sales  
9 volumes change, these costs are not affected, but continue to be incurred, making them  
10 fixed or demand-related in nature.

11 It is not proper to classify a portion of the fixed costs related to production based  
12 on energy. However, if an attempt were made to increase the allocation of investment to  
13 one group of customers, on the theory that those customers benefit more than others  
14 from the lower energy costs that result from the operation of a base load plant as  
15 opposed to a peaking plant, the analysis should be carried to its logical conclusion. The  
16 logical conclusion would be to fairly and symmetrically allocate energy costs to the group  
17 of customers who are forced to bear the higher capital costs allocated to them on a kWh  
18 basis. Energy costs allocated to the high load factor class should recognize lower  
19 operating costs which result from the higher capital costs of the base load plants.  
20 Unfortunately, in the past, when the peak and average method was proposed, the lower  
21 fuel costs were not properly assigned to the industrial class of customers.

1    **Q     BASED ON THIS ANALYSIS, DO YOU BELIEVE THAT IT IS APPROPRIATE TO**  
2           **ALLOCATE PRODUCTION OR TRANSMISSION INVESTMENT COSTS ON A**  
3           **METHOD THAT IS SUBSTANTIALLY A KWH ALLOCATION, SUCH AS THE PEAK**  
4           **AND AVERAGE METHOD?**

5    **A     No.** These kWh types of allocation methods are totally inappropriate. They give far too  
6           much weight to energy consumption, and understate the importance of peak loads that  
7           are dominant on the SCE&G electric system.

8    **Q     ARE THERE ANY OTHER REASONS WHY YOU DISAGREE WITH THE**  
9           **CLASSIFICATION OF FIXED COSTS PARTLY ON THE BASIS OF ENERGY?**

10   **A     Yes.** Since rate design should be based on cost of service, significant rate design  
11           problems will result from the allocation of fixed costs on an energy basis. First,  
12           allocation of fixed costs partly based on energy consumption makes the rates less stable  
13           than they would otherwise be, and second, allocation of fixed costs partly based on  
14           energy reduces the incentive given to customers by off-peak pricing provisions.  
15           Allocating production investment on an energy basis signals customers that a demand  
16           created at the peak hour is the same as a demand created during the off-peak hour.  
17           Customers that shift loads in response to time-of-day rates will not be treated fairly by a  
18           kWh type of costing methodology, such as the peak and average method.

19   **Q     PLEASE EXPLAIN.**

20   **A     With respect to stability, if a significant proportion of fixed costs is classified on the basis**  
21           **of energy and the level of kWh sales decreases (as often happens during an economic**  
22           **downturn), the utility's revenues will drop more than its costs, since fixed costs are being**  
23           **collected in the energy or variable portion of the rate. On the other hand, a proper**  
24           **recognition of the differentiation between demand and energy costs would, under these**

1 circumstances, cause revenues to decline in closer correspondence to the decline in  
2 costs, since the energy charges would basically recover those costs which do, in fact,  
3 vary with the number of kWh sold.

4 With respect to the concept of off-peak pricing, classification of a portion of the  
5 demand-related costs based on energy reduces the savings to the customer due to  
6 increased use during off-peak hours. For example, if a customer were to increase his  
7 consumption during off-peak hours (without changing his demands or energy  
8 consumption during the on-peak hours), this classification method would allocate more  
9 investment in fixed costs to the customer than before, since the number of kWh added  
10 during the off-peak period would increase the allocation of fixed costs, even though the  
11 system's total capacity and capacity-related costs had not increased. This reduces the  
12 savings that would be available to the customer as a result of adding load off-peak as  
13 opposed to on-peak. This inequity is exacerbated when viewed by a customer who  
14 shifts summer loads to the remaining eight months of the year. The customer would  
15 receive lower rates, temporarily, but would not receive an appropriate reduction in the  
16 allocation of demand-related costs. Therefore, this customer can expect an  
17 above-average increase in the next rate case as a reward for his shifting. This result is  
18 a further demonstration of the inappropriateness of an energy type (average demand)  
19 approach to the allocation of fixed costs. Allocating fixed costs on an energy basis is in  
20 direct conflict with the current and proposed rate structure and the time-of-day/seasonal  
21 load management type rates previously approved by this Commission.

**Distribution of Revenue Increase Proposed by SCE&G**

**Q HAVE YOU REVIEWED THE MANNER IN WHICH SCE&G PROPOSES TO INCREASE THE RATES CHARGED TO ITS VARIOUS CUSTOMER CLASSES?**

**A** Yes, I have. I focus on the total requested increase rather than the three individual phases. Schedule 1 of Exhibit NP-2 summarizes SCE&G's proposal. SCE&G proposes to increase residential revenues by 9.69%, small general service revenues by 9.53%, medium general service by 9.24%, large general service revenues by 9.19%, and lighting class revenues by 11.03%. The distribution of the increase as presented by the Company is based on its stated goal of cost-based pricing, which would send clear price signals, promote the efficient use of electricity, complement demand-side management efforts, allow rates to remain competitive, encourage higher load factors, foster energy conservation, and promote off-peak use.

**Results of Cost of Service Studies**

**Q HAVE YOU EXAMINED THE CLASS RATES OF RETURN FOR THE TEST YEAR?**

**A** Yes. Schedule 2 of Exhibit NP-2 shows rates of return and indexes, for each class of service under present and SCE&G proposed rates utilizing the summer coincident peak method of cost allocation.

Under the allocation of the increase proposed by SCE&G, all classes move toward cost of service. The rates of return for all rate classes are very close to the system average rate of return under the revenue allocation proposed by SCE&G.

SCE&G's proposed distribution of the increase as presented clearly makes a meaningful movement toward cost-based rates for all rate classes and should be adopted in this proceeding.

1 For this case in which the data for the LGS class cannot be considered normal,  
2 the measured movement toward cost of service is appropriate.

3 **Q PLEASE EXPLAIN YOUR CONCERN REGARDING NORMAL DATA FOR THE LGS**  
4 **CLASS.**

5 **A** The severe economic conditions that existed during the test year cannot be considered  
6 normal. Therefore, the loads, sales levels and revenues used in the cost of service  
7 study cannot be considered normal. This is a particular concern with respect to the  
8 large general service class. In that regard, Mr. Kevin Marsh, President and Chief  
9 Operating Officer of SCE&G, states the following:

10 "There are a number of years where recessions have driven modest  
11 declines in sales. An exception to this is 2009, in which the system  
12 experienced a significant sales decline as a result of the severe  
13 recession. Following all past recessions, SCE&G has seen growth in  
14 sales rebound." (Marsh Direct Testimony, page 32)

15 It is clear that the test year cost of service study cannot be considered normal.

16 **Q WHAT IS YOUR RECOMMENDATION WITH RESPECT TO A COST-BASED**  
17 **DISTRIBUTION OF ANY INCREASE AWARDED TO SCE&G IN THIS PROCEEDING?**

18 **A** Based on information provided by SCE&G, any rate increase granted should be  
19 distributed to classes proportional to the quantities in Column 3 of Schedule 1 of  
20 Exhibit NP-2. The large general class increase should be no more than 9.19%  
21 assuming SCE&G receives its entire rate increase request. If SCE&G receives one-half  
22 of its rate request, these quantities should be reduced by one-half. For example, if  
23 SCE&G is granted a \$98.8 million or 4.76% overall increase, the large general service  
24 class increase should be no more than 4.59%.

**Rate Design**

**Q HAVE YOU REVIEWED THE MANNER IN WHICH SCE&G PROPOSES TO ADJUST ITS VARIOUS INDUSTRIAL RATE SCHEDULES?**

**A** Schedule 3 of Exhibit NP-2 shows the rate design and rate increase by component as proposed by SCE&G for Rate 23, Industrial Power Service. As presented by SCG&E, the demand component of the rate is being increased by approximately 17.4% and the energy component of the rate is being increased by 4.5%. Schedule 4 of Exhibit NP-2 is a similar analysis for Rate 24, large general service time-of-use. The demand component of the rate has increased by approximately 19.5% and the energy rate has increased by about 5.5%.

SCE&G proposes to place the majority of the increase in the demand component of the rate, which is appropriate. Increasing the demand charge is consistent with cost of service. Fuel cost changes are the subject of fuel adjustment proceedings and rate changes associated with changes in fuel costs are the subject of separate proceedings. Base rate changes generally do not consider fuel costs. The fuel cost level included in rates remains constant at \$0.03646 per kWh under SCE&G's proposed rate design. The proposed rate design levels should, of course, be reduced to the extent that SCE&G's overall requested increase is reduced by the Commission.

SCE&G is proposing to mitigate the impact of the increase on its customers by implementing the increase in three phases. The Company is proposing that approximately \$66.1 million or 3.2% (Phase I) be effective July 15, 2010; \$63.5 million or 3.1% (Phase II) be effective January 1, 2011; and \$67.9 million or 3.3% (Phase III) be effective July 1, 2011.

1    **Q     DO YOU AGREE WITH SCE&G'S PROPOSAL TO PHASE-IN THE INCREASE?**

2    A     Yes. The phase-in approach is welcomed and is appropriate under the current  
3         economic conditions. I recommend that the increase be mitigated and phased-in to the  
4         extent practicable.

5    **Q     DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

6    A     Yes.

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**Qualifications of Nicholas Phillips, Jr.**

1    **Q     PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

2    A     Nicholas Phillips, Jr. My business address is 16690 Swingley Ridge Road, Suite 140,  
3         Chesterfield, MO 63017.

4    **Q     PLEASE STATE YOUR OCCUPATION.**

5    A     I am a consultant in the field of public utility regulation and am a principal with the firm  
6         of Brubaker & Associates, Inc. (BAI), energy, economic and regulatory consultants.

7    **Q     PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL**  
8         **EMPLOYMENT EXPERIENCE.**

9    A     I graduated from Lawrence Institute of Technology in 1968 with a Bachelor of Science  
10        Degree in Electrical Engineering. I received a Master's of Business Administration  
11        Degree from Wayne State University in 1972. Since that time I have taken many  
12        Masters and Ph.D. level courses in the field of Economics at Wayne State University  
13        and the University of Missouri.

14           I was employed by The Detroit Edison Company in June of 1968 in its  
15        Professional Development Program. My initial assignments were in the engineering  
16        and operations divisions where my responsibilities included the overhead and  
17        underground design, construction, operation and specifications for transmission and  
18        distribution equipment; budgeting and cost control for operations and capital  
19        expenditures; equipment performance under field and laboratory conditions; and  
20        emergency service restoration. I also worked in various districts, planning system  
21        expansion and construction based on increased and changing loads.

1           Since 1973, I have been engaged in the preparation of studies involving revenue  
2 requirements based on the cost to serve electric, steam, water and other portions of  
3 utility operations.

4           Other responsibilities have included power plant studies; profitability of various  
5 segments of utility operations; administration and recovery of fuel and purchased power  
6 costs; sale of utility plant; rate investigations; depreciation accrual rates; economic  
7 investigations; the determination of rate base, operating income, rate of return; contract  
8 analysis; rate design and revenue requirements in general.

9           I have held various positions including Supervisor of Cost of Service, Supervisor  
10 of Economic studies and Depreciation, Assistant Director of Load Research, and was  
11 designated as Manager of various rate cases before the Michigan Public Service  
12 Commission and the Federal Energy Regulatory Commission. I was acting as Director  
13 of Revenue Requirements when I left Detroit Edison to accept a position at  
14 Drazen-Brubaker & Associates, Inc., (DBA) in May of 1979.

15           The firm of Drazen-Brubaker & Associates, Inc. was incorporated in 1972 and  
16 has assumed the utility rate and economic consulting activities of Drazen Associates,  
17 Inc., active since 1937. In April 1995 the firm of Brubaker & Associates, was formed. It  
18 includes most of the former DBA principals and staff.

19           Our firm has prepared many studies involving original cost and annual  
20 depreciation accrual rates relating to electric, steam, gas and water properties, as well  
21 as cost of service studies in connection with rate cases and negotiation of contracts for  
22 substantial quantities of gas and electricity for industrial use. In these cases, it was  
23 necessary to analyze property records, depreciation accrual rates and reserves, rate  
24 base determinations, operating revenues, operating expenses, cost of capital and all  
25 other elements relating to cost of service.

1 In general, we are engaged in valuation and depreciation studies, rate work,  
2 feasibility, economic and cost of service studies and the design of rates for utility  
3 services. In addition to our main office in St. Louis, the firm also has branch offices in  
4 Phoenix, Arizona and Corpus Christi, Texas.

5 **Q WHAT ADDITIONAL EDUCATIONAL, PROFESSIONAL EXPERIENCE AND**  
6 **AFFILIATIONS HAVE YOU HAD?**

7 A I have completed various courses and attended many seminars concerned with rate  
8 design, load research, capital recovery, depreciation, and financial evaluation. I have  
9 served as an instructor of mathematics of finance at the Detroit College of Business  
10 located in Dearborn, Michigan. I have also lectured on rate and revenue requirement  
11 topics.

12 **Q HAVE YOU PREVIOUSLY APPEARED BEFORE A REGULATORY COMMISSION?**

13 A Yes. I have appeared before the New Jersey Board of Public Utilities, the Public Service  
14 Commissions of Arkansas, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland,  
15 Michigan, Missouri, Montana, New York, North Carolina, Ohio, Pennsylvania, South  
16 Carolina, South Dakota, Virginia, West Virginia, and Wisconsin, the Lansing Board of  
17 Water and Light, and the Council of the City of New Orleans in numerous proceedings  
18 concerning cost of service, rate base, unit costs, pro forma operating income,  
19 appropriate class rates of return, adjustments to the income statement, revenue  
20 requirements, rate design, integrated resource planning, power plant operations, fuel  
21 cost recovery, regulatory issues, rate-making issues, environmental compliance, avoided  
22 costs, cogeneration, cost recovery, economic dispatch, rate of return, demand-side  
23 management, regulatory accounting and various other items.

**SOUTH CAROLINA ELECTRIC & GAS COMPANY**  
**Docket No. 2009-489-E**

**Major Class Load Factors**  
**for the Year Ended September 30, 2009**

<u>Line</u>	<u>Rate Class</u>	<u>Energy Requirement (MWh)</u> (1)	<u>Demand at System Peak (MW)</u> (2)	<u>Load Factor Based on Four-Hour Average Coincident Demand on System Peak Day</u> (3)
1	Residential	8,261,821	1,918	49.18%
2	Small General Service	3,387,419	721	53.66%
3	Medium General Service	2,594,814	462	64.13%
4	Large General Service	7,085,067	952	84.98%
5	Street Lighting	<u>304,873</u>	<u>-</u>	N/M
6	Total Retail	21,633,994	4,052	60.95%

**SOUTH CAROLINA ELECTRIC & GAS COMPANY**  
**Docket No. 2009-489-E**

**Major Class Sales by Voltage Level**

<u>Line</u>	<u>Rate Class</u>	<u>Total Retail (1)</u>	<u>Secondary (2)</u>	<u>Primary (3)</u>	<u>Subtrans- mission (4)</u>	<u>Trans- mission (5)</u>
1	Residential	100.0%	100.0%	0.0%	0.0%	0.0%
2	Small General Service	100.0%	99.6%	0.4%	0.0%	0.0%
3	Medium General Service	100.0%	99.1%	0.8%	0.1%	0.0%
4	Large General Service	100.0%	0.0%	37.7%	7.1%	55.2%
5	Street Lighting	100.0%	100.0%	0.0%	0.0%	0.0%
6	Total Retail	100.0%	62.4%	14.3%	2.7%	20.7%

**SOUTH CAROLINA ELECTRIC & GAS COMPANY**  
**Docket No. 2009-489-E**

**Megawatthour Sales, Number of Customers  
and Kilowatthour Sales per Customer  
for the Year Ended September 30, 2009**

<u>Line</u>	<u>Rate Class</u>	<u>Energy Sales (MWh) (1)</u>	<u>Number of Customers (2)</u>	<u>Kilowatthour Sales per Customer (3)</u>
1	Residential	7,850,315	558,839	14,048
2	Small General Service	3,218,810	89,988	35,769
3	Medium General Service	2,468,991	2,880	857,288
4	Large General Service	6,903,926	316	21,847,868
5	Street Lighting	<u>289,687</u>	<u>240,986</u>	1,202
6	Total Retail	20,731,729	893,009	23,216

**SOUTH CAROLINA ELECTRIC & GAS COMPANY**  
**Docket No. 2009-489-E**

**Rate Base Expressed  
on a per Kilowatthour Sold Basis  
for the Year Ended September 30, 2009**

<u>Line</u>	<u>Rate Class</u>	<u>Rate Base (000) (1)</u>	<u>Energy Sales (MWh) (2)</u>	<u>Rate Base Expressed on a per kWh Basis (3)</u>
1	Residential	\$ 2,367,804	7,850,315	30.16 ¢
2	Small General Service	860,629	3,218,810	26.74
3	Medium General Service	498,228	2,468,991	20.18
4	Large General Service	938,153	6,903,926	13.59
5	Street Lighting	<u>156,092</u>	<u>289,687</u>	53.88
6	Total Retail	\$ 4,820,906	20,731,729	23.25 ¢

**SOUTH CAROLINA ELECTRIC & GAS COMPANY**  
**Docket No. 2009-489-E**

**Operating Expenses Expressed  
on a per Kilowatthour Sold Basis  
for the Year Ended September 30, 2009**

<u>Line</u>	<u>Rate Class</u>	Operating Expenses (000) (1)	Energy Sales (MWh) (2)	Expenses Expressed on a per kWh Basis (3)
1	Residential	\$ 786,482	7,850,315	10.02 ¢
2	Small General Service	297,855	3,218,810	9.25
3	Medium General Service	189,218	2,468,991	7.66
4	Large General Service	426,000	6,903,926	6.17
5	Street Lighting	<u>41,023</u>	<u>289,687</u>	14.16
6	Total Retail	\$ 1,740,578	20,731,729	8.40 ¢

**SOUTH CAROLINA ELECTRIC & GAS COMPANY**  
**Docket No. 2009-489-E**

**Load Forecast**  
**for the Years 2010 through 2024**

<u>Line</u>	<u>Year</u>	<u>Summer Peak (MW)</u> (1)	<u>Winter Peak (MW)</u> (2)	<u>Energy Sales (GWh)</u> (3)	<u>Load Factor</u> (4)
1	2010	4,752	4,119	22,871	54.9%
2	2011	4,852	4,209	23,373	55.0%
3	2012	4,948	4,216	23,505	54.1%
4	2013	5,020	4,251	23,713	53.9%
5	2014	5,089	4,289	23,837	53.5%
6	2015	5,157	4,352	24,109	53.4%
7	2016	5,241	4,430	24,453	53.1%
8	2017	5,324	4,506	24,779	53.1%
9	2018	5,406	4,586	25,105	53.0%
10	2019	5,490	4,683	25,466	53.0%
11	2020	5,614	4,772	25,940	52.6%
12	2021	5,744	4,881	26,522	52.7%
13	2022	5,871	4,988	27,093	52.7%
14	2023	5,991	5,085	27,611	52.6%
15	2024	6,105	5,179	28,114	52.4%

**SOUTH CAROLINA ELECTRIC & GAS COMPANY**  
**Docket No. 2009-489-E**

**Summary of  
SCE&G Proposed Rate Increase  
by Customer Classes**

<u>Line</u>	<u>Rate Class</u>	Current	SCE&G	SCE&G	
		Revenue	Proposed	Proposed Increase	
		(000)	Phase III	Amount	Percent
		(1)	Revenue	(000)	(4)
			(2)	(3)	
1	Residential	\$ 927,122	\$ 1,016,922	\$ 89,800	9.69%
2	Small General Service	361,830	396,330	34,499	9.53%
3	Medium General Service	222,894	243,493	20,600	9.24%
4	Large General Service	510,080	556,977	46,897	9.19%
5	Street Lighting	<u>52,341</u>	<u>58,115</u>	<u>5,774</u>	11.03%
6	Total Retail	\$ 2,074,268	\$ 2,271,838	\$ 197,570	9.52%

**SOUTH CAROLINA ELECTRIC & GAS COMPANY**  
**Docket No. 2009-489-E**

**Rates of Return and Indexes**  
**at Present and Company Proposed Rates**  
**12 Months Ended September 30, 2009**

<u>Line</u>	<u>Rate Class</u>	<u>Present Rates</u>		<u>Proposed Rates</u>	
		<u>Rate of</u>	<u>Index</u>	<u>Rate of</u>	<u>Index</u>
		<u>Return</u>	<u>Index</u>	<u>Return</u>	<u>Index</u>
		(1)	(2)	(3)	(4)
1	Residential	6.48%	100	8.82%	98
2	Small General Service	7.91%	122	10.37%	115
3	Medium General Service	6.74%	104	9.31%	103
4	Large General Service	4.94%	76	8.02%	89
5	Street Lighting	7.68%	118	9.95%	110
6	Total	6.50%	100	9.03%	100

**SOUTH CAROLINA ELECTRIC & GAS COMPANY**  
**Docket No. 2009-489-E**

**Comparison of Present and Proposed  
Demand and Energy Components  
for Rate 23, Industrial Power Service**

<u>Line</u>	<u>Description</u>	<u>Present Rate</u> (1)	<u>SCE&amp;G Proposed Phase III Rate</u> (2)	<u>SCE&amp;G Proposed Increase</u>	
				<u>Amount</u> (3)	<u>Percent</u> (4)
	Basic Facilities Charge:				
1	Per Month	\$ 1,500	\$ 1,725	\$ 225	15.00%
	Demand Charge:				
2	All kW	\$ 12.48	\$ 14.65	\$ 2.17	17.39%
	Energy Charge:				
3	All kWh	\$ 0.04536	\$ 0.04740	\$ 0.00204	4.50%

**SOUTH CAROLINA ELECTRIC & GAS COMPANY**  
**Docket No. 2009-489-E**

**Comparison of Present and Proposed  
Demand and Energy Components  
for Rate 24, Large General Service Time-of-Use**

Line	Description	Present Rate (1)	SCE&G	SCE&G	
			Proposed Phase III Rate (2)	Proposed Increase	
				Amount (3)	Percent (4)
Basic Facilities Charge:					
1	Per Month	\$ 1,500	\$ 1,725	\$ 225	15.00%
Demand Charge:					
On-Peak Billing Demand kW					
2	Summer (Jun-Sep)	\$ 15.13	\$ 18.10	\$ 2.97	19.63%
3	Non-Summer (Oct-May)	\$ 10.61	\$ 12.67	\$ 2.06	19.42%
4	Off-Peak Billing Demand kW	\$ 4.55	\$ 5.43	\$ 0.88	19.34%
Energy Charge:					
On-Peak kWh					
5	Summer (Jun-Sep)	\$ 0.07518	\$ 0.07925	\$ 0.00407	5.41%
6	Non-Summer (Oct-May)	\$ 0.05424	\$ 0.05724	\$ 0.00300	5.53%
7	Off-Peak kWh	\$ 0.04153	\$ 0.04403	\$ 0.00250	6.02%